

IN THE UNITED STATES PATENT AND TRADEMARK OFFICE

Applicant(s): Craig N. Schubert, et. al.

Serial No.: 10/565,466

Group Art Unit: 1797

Filed: January 20, 2006

Examiner: Ives J. Wu

For: REGENERATION OF ACID GAS-CONTAINING TREATMENT FLUIDS

Dow Reference: 63149A

I hereby certify that this paper (along with any paper referred to as being attached or enclosed) is being transmitted via the Office electronic filing system in accordance with § 1.6(a)(4).

Dated: June 22, 2006
Electronic Signature for Paul D. Hayhurst: /Paul D. Hayhurst/

Assistant Commissioner for Patents
Washington, D.C. 20231

Sir:

DECLARATION OF PRIOR INVENTION UNDER 37 C.F.R. § 1.131

We, Dr. Craig N. Schubert. and Dr. Timothy C. Frank do hereby declare that:

1) We are the same Craig N. Schubert. and Timothy C. Frank who are co-inventors of the subject matter of the above identified patent application, as well as named co-applicants on the above identified patent application before the United States Patent and Trademark Office.

2) We are aware that all claims of the above identified patent application stand rejected by the Examiner under 35 U.S.C. 102(e) or 35 U.S.C. 103(a) over Rochelle, either alone or in combination with other references, in an office action dated February 25, 2009, Rochelle having an effective reference date of May 5, 2003 (hereinafter "102(e) reference date") that is before the earliest filing date to which our above identified patent application claims benefit of priority, namely July 22, 2003, the filing date of US Provisional Application Serial Number 60/489,042.

3) The subject matter of our claims was invented by ourselves (hereinafter "Inventors") in the United States of America before the above 102(e) reference date.

4) Evidence of the above prior invention date is established by the fact that the Inventors conceived of their invention and reduced it to practice prior to the above 102(e) reference date; all of said efforts relied on herein to demonstrate prior invention having taken place in the United States of America; and we have never abandoned, suppressed or concealed the invention contained in the above identified patent application.

5) Photocopies of original exhibits, drawings, and records demonstrating that the foregoing events took place and the relevance thereof comprise the following events that were recorded in documents issued in the ordinary course of business and maintained by ourselves or others acting under our direction and control for normal business purposes in an appropriate manner to ensure accuracy, reliability and availability for business use.

6) In the photocopies, all dates have been removed, pursuant to MPEP 715.07, but the invention was in our possession prior to the 102(e) reference date. Certain information relating to corporate structure has also been removed.

7) Evidence of the conception and reduction to practice of the present invention is found in a Disclosure of Invention, submitted to the IP Administrative Section of the Legal Department of The Dow Chemical Company, signed by the Inventors and witnessed by Peter C. Rooney, wherein the invention was disclosed for purposes of preparing a patent application by the Intellectual Property Law group of The Dow Chemical Company. The Invention Disclosure was signed by the inventors, witnessed by Peter C. Rooney, approved by the R&D Manager, Karen Kenny, received by the IP Administrative Section, and assigned to an attorney all prior to May 5, 2003. A copy of said document confirming these acts is attached hereto as Exhibit A.

8) Additional evidence of the present inventors' efforts to duly reduce the foregoing invention to practice are also found in a "CRI" Report (hereinafter "Report") of The Dow Chemical Company that was issued internally to its author, C.N Schubert, who is one of the Inventors, prior to May 5, 2003. The Report is de facto incorporated by reference into the Disclosure of Invention, mentioned hereinabove, at the first line of page 3 of the Disclosure of Invention. The report was also witnessed by Peter C. Rooney. Table 1, at page 3 of the Report, describes two

cases wherein the reboiler pressure is over 50 psia, namely, Case 2 with a pressure of 55.4 psia and Case 3 with a pressure of 135 psia. A copy of said document confirming these acts is attached hereto as Exhibit B. Due to the fact that Report may contain the confidential information of third parties, several pages have been omitted to protect that information.

9) The undersigned declare further that all statements made herein of their own knowledge are true and that all statements made on information and belief are believed to be true; and further that these statements were made with the knowledge that willful false statements and the like so made are punishable by fine or imprisonment, or both, under Section 1001 of Title 18 of the United States Code and that such willful false statements may jeopardize the validity of the application or any patent issuing thereon.

6/11/09

Date

6/15/09

Date

Craig N Schubert

DR. CRAIG N. SCHUBERT

Timothy C. Frank

DR. TIMOTHY C. FRANK

INVENTION DISCLOSURE FORM

- Please check to make sure you are using the most current version of this form <Double Click Here>.
- This form contains electronic helps and examples. Click on the blue links to view these.
- If you are new to filling out this form or would appreciate seeing an Example Completed Form, please go to this link.
- If you have problems with this form, please contact [Feedback Form](#).
- If you have comments or suggestions for improving this form, please complete the [Feedback Form](#).

Invention Pre-Disclosures: Items 1c, 2a, and 5-7 may be optional if this form is being used as an idea disclosure or invention pre-disclosure form: contact your Intellectual Capital Manager (ICM) for instructions. If this form is being submitted to Intellectual Property (IP) Law for filing a patent application, then all of Items 1-14 must be completed.

SUMMARY OF THE INVENTION

(Invention?)

1a. Explain what problem you were seeking to solve; or what improvement you were seeking to achieve? Ex.

• Response: Reduce costs associated with acid gas reinjection

1b. Describe briefly: What was your solution to the problem; or what improvement did you achieve; or what desirable unexpected effect did you discover? Also, for what primary purpose can the invention be used? Ex.

• Response: approx. 25-50 % of compression capital and operating costs eliminated if amine stripper is operated at high pressure

1c. For what alternative purposes or fields can the invention be employed? Help & Ex.

• Response: reduction of compression costs associated with co2 sequestration

BACKGROUND

A LITERATURE SEARCH IS REQUIRED

2a. Search & Analysis Details: Help & Ex.

• Who performed the search(es) (self, BIC, ICM, etc.) and when was the search(es) performed?

• Response: Craig Schubert

• What search tools/databases were used:

☐ Derwent ☐ CAS ☐ SciFinder ☒ MicroPatent ☐ Other

• If "Other" then List Search Tools, Databases:

• What documents were searched:

☒ Patents ☐ Literature ☐ Internal Dow Documents ☐ Other

• If "Other" then List Documents:

• Describe the conceptual focus of the search.

• Response: high pressure regeneration of acid gas removal solvents

2b. Search & Analysis Results: Provide a list of the literature and patent publications of which the contributors are aware that relate to the invention, and explain how each document relates to the invention. If this list includes any non-patent references, please provide a copy of those documents. Help & Ex.

Keep Your Explanation Factual: Do Not Include Speculations or Opinions.

• Response:

USP 5,766,548 – Includes a listing of typical amine solvent temperatures at various locations in the plant. These authors list 250 – 280 F as a typical reboiler temperature range.

USP 5,435,977 – A method of regenerating spent alkanolamine using modified regeneration tower. The modification consists of at least one internal flash section in the bottom portion of the regenerator.

USP 4,299,801 – Method for regenerating spent alkanolamine absorbing solution containing H₂S and CO₂. Two desorption stages are used to produce two acid gas streams – one rich in CO₂ and the other rich in H₂S. Both regeneration stages are conducted at conventional temperature and pressure (8-12 psig) conditions.

USP 4,452,763 – A process for regeneration of spent aqueous alkanolamine or dialkanolamine. Energy consumption is reduced by minimizing the amount of water circulated (10 to 35 wt % water) and by minimizing the amount of reflux returned to the top of the regeneration tower. No advantage to operation at high regeneration pressure is disclosed. Regenerator bottoms temperature in the example is 140 C, consistent with normal practice.

USP 4,152,217 – A process for regenerating a spent aqueous amine absorbent. Improvement involves splitting the spent absorbent into two portions. One portion is not heated but is directed to the regenerator top. The other portion

is heated and introduced at an intermediate height of the regenerator. No advantage to operation at high regeneration pressure is disclosed. The example includes a reboiler temperature of 262 F, consistent with normal operating practice.

US 2002/0007733 – Use of fuel gas to strip benzene, toluene and xylene (BTEX) from a liquid amine stream. This stripping is accomplished in a separate vessel. The liquid amine exiting the BTEX stripper is then heated and passed to a conventional stripper. No teaching of any advantage to operating at high stripper pressure.

USP 5,660,603 – Removal of CO₂ at high pressure from natural gas by contacting with water or seawater. Absorber temperature and pressure are selected to allow the formation of pre-solid hydrates in the aqueous phase. Regeneration of the aqueous phase is accomplished by altering the temperature and pressure to allow decomposition of the pre-solid hydrate structures. This pressure can be greater than or less than the absorption pressure.

Acid Gas Injection – A Decade of Operating History in Canada (attached)

3. **Other Technology:** Other than the technology described in these literature and patent publications (Items 2a and 2b), what is the closest technology of which the contributors are aware that is or has been already employed for this problem/area? Help

• Response: none known

- 4a. **Differences:** What are the differences between this invention and the prior technology noted in Items 2 and 3? Specifically, what makes this invention unique or different from the prior technology; or what was lacking from the prior technology that your invention supplies? Ex.

• Response: prior art (excepting USP 5,660,603) involves regeneration of acid gas at low pressure (22-30 psia) and low temperature (250-285 F). Compressing this stream for reinjection into typical formations requires 4 stages of compression. However, operating the regeneration tower at high temperature (360 F) and high pressure (130 psia) would eliminate approx. 1/2 of the required compression and associated costs.

- 4b. **Advantages:** What are the advantages of this invention over the prior technology noted in Items 2 and 3? Help & Ex.

• Response: reduced cost of compression

DETAILED DESCRIPTION

- 5a. **List elements/components/steps that you believe are useful in the invention.** Help & Ex.

• Response:

Component A: Regeneration of solvent at high pressure to reduce compression costs

Component B: Use of extra large lean rich exchanger to minimize cost of operating at high T&P

- 5b. **List additional elements/components/steps that you believe can be added to those listed in 5a.** Help & Ex.

• Response: Addition of volatile component to reduce reboiler T requirement

6. **List those substitute or alternative elements/components/steps/orders that may be used in place of each of the items listed in Items 5a and 5b.** Help

• Response: none known

7. **Define the permissible ranges of the components and conditions listed in Items 5 and 6, as well as those ranges under which the invention demonstrates its best utility.** Help & Ex.

• Response: see cri

EXAMPLES

8. **Examples:** Describe at least one representative working example demonstrating the invention in sufficient detail that others outside of Dow could repeat it. Help & Ex.

Attach and Reference Additional Pages as Needed

- Include—if applicable—performance data, chemical properties and analytical results.
- If appropriate, use chemical formulae.
- Where use of an experimental or custom-synthesized material is reported, it must also be described by, e.g., synthetic method, Databook No., Lot No., Pilot Plant name, etc.
- Use SI (metric) units in the description.
- Clearly identify characterization methods (e.g., ASTM, ISO, etc.), if applicable.

• Response: see attached CRI

FIGURES & TABLES

9. **Figures/Tables:** If figure(s) or table(s) would improve the understanding of the invention, or enhance the explanation, please attach or include the figure(s) or table(s) and make appropriate reference(s) to them in the text. Help

LEGAL & PROCEDURAL BACKGROUND**10a. Where and how is the invention documented?**

List databook numbers and pages, CRI Report Nos. (attach copies of e-mails, meeting minutes, etc.). Help

• Response: see attached CRI

10b. Countries Involved

In what country or countries was the invention made or was work done on the invention?

• Response: USA

10c. Disclosures

Has the invention or information relating to the invention been disclosed to anyone outside of Dow? ... ☐ Yes ☒ No
If so, to whom? When? Help

• Response:

10d. Commercial Activity: (either or both of (i) and (ii) may apply to your invention)

(i) If your invention is a "product",

Has the "product" been sold or offered for sale to anyone? ☐ Yes ☒ No

Has Dow ordered or purchased a prototype of the "product" made at Dow's request by a third party
(e.g., a contract manufacturer)? ☐ Yes ☒ No

Has Dow accepted an order for the "product"? ☐ Yes ☒ No

(ii) If your invention is a "process",

Has the "process" been sold or licensed to anyone? ☐ Yes ☒ No

Has the "process" been used for any commercial purpose by Dow or a licensee or other party? Help... ☐ Yes ☒ No

11. External Funding: Was the invention made or completed:

(a) In the course of work under a contract with or funding by any government agency? ☐ Yes ☒ No

Contract No. or Grant No.:

(b) In connection with any other Party? ☐ Yes ☒ No

Agreement No.

Name of Other Party:

(c) Do any of the inventors have obligations to a prior employer, or any party other than Dow, that should be considered to ensure that no proprietary information of a third party has been disclosed in or used in making this invention?

☐ Yes ☒ No

Name of Such Inventor(s):

ICM & IP ADMINISTRATIVE SECTION (For Use by ICM & IP Only)			
ICM Administrative		ICM Ref. No.	IP Administrative
Primary Business Name			Disclosure No. 6349
Primary Subject Code			IP Receipt Date
Primary ICMT Code			Assigned to Karadzik
Secondary ICMT Code			
(PTF) ID(s)			
INCA Code - Business Name [LV30]			ArbEG
INCA Code - Value Center [LV40]			Receipt Date from Inventor
INCA Code - Performance Center [LV50]			

(Continue Completing Form)

TITLE

12. Provide a Short (less than 20 words) Descriptive Phrase or Sentence that Summarizes the Invention.

• Response: High Pressure Regeneration of Acid Gas Removal Solvent

EXECUTIVE SUMMARY

13. Summarize (in 100 words or less) what the invention is and does and to what technology area it relates.

• Response: This invention provides a means to regenerate acid gas removal solvents at high pressure to facilitate disposal of the acid gases in underground reservoirs or placement into high pressure tanks or pipelines for transportation or storage purposes.

CONTRIBUTORS

14. Information for Person(s) Contributing to this Disclosure of Invention:

(If there are more contributors, please <Double Click Here> to add another page of information boxes.)

(If any of the contributors were employed at a German entity at the time of their contribution, please <Double Click Here> to add the ArbEG section to the end of this form, and then complete that section.)

Name (Please type or print):		Name (Please type or print):	
Last Name <u>Schubert</u>		Last Name <u>Frank</u>	
First <u>Craig</u>	Middle <u>Norman</u>	First <u>Timothy</u>	Middle <u>Charles</u>
Home Address <u>220 Moss Rose Lane</u>		Home Address <u>5001 Foxpoint Circle</u>	
City <u>Lake Jackson</u>	County <u>Brazoria</u>	City <u>Midland</u>	County <u>Midland</u>
State <u>Texas</u>	Postal Code <u>77566</u>	State <u>Michigan</u>	Postal Code <u>48642</u>
Country <u>USA</u>		Country <u>USA</u>	
Citizenship <u>USA</u>		Citizenship <u>USA</u>	
Employed by <u>Dow Chemical Company</u>		Employed by <u>Dow Chemical Company</u>	
Occupation/Profession <u>Engineer</u>		Occupation/Profession <u>Engineer</u>	
Division _____	Bldg. _____	Division _____	Bldg. _____
Department _____		Department _____	
Phone _____	Master No. _____	Phone _____	Master No. _____
Were you employed at a German entity at the time of your contribution to this invention? Yes _____ No <u>X</u>		Were you employed at a German entity at the time of your contribution to this invention? Yes _____ No <u>X</u>	
Signature: <u>Craig Schubert</u>		Signature: <u>Timothy C Frank</u>	

Send this completed form to the Appropriate ICM for approval and submission to IP Law.

(Go to: _____ and look through the "IC Manager" Alignment Chart to determine which Intellectual Capital Manager is most closely associated with this invention.) [Help](#)

ICMT ADMINISTRATIVE SECTION
(For Use by ICM & IP Only)

ICMT Approval	
My initials and date are included on <u>all</u> pages of this Disclosure and its attachments.	
I have understood the invention from reading this Disclosure and its attachments; I believe this Invention Disclosure is complete.	
ICM Name	<i>Peter C. Rooney</i>
ICM Signature	<i>Peter Rooney</i>
Date	

Non-ICM Approvers (use as required by business)			
Department Head Name	Approval Signature	Date	Employee No.
<i>Karen Kenney</i>	<i>E-mail attached</i>		
R&D Manager Name	Approval Signature	Date	Employee No.

DOW CONFIDENTIAL INFORMATION

Limited Distribution R&D Report		CRI Number
The Dow Chemical Company		Laboratory Report Code CRILabCodeLTD
Department Specialty Alkanolamines	Geographic Location Freeport, TX	Date Issued
74 pages in full report	Databook Number(s)	
Title High Pressure Regeneration of Acid Gas Removal Solvents		
Author(s): Last Name and Initials (Master Numbers) Schubert, C.N. (
Author Signature(s)		
Reviewer and/or Supervisor Name(s) Bedell, S.A.; Kenny, K.	Reviewer and/or Supervisor Signature(s)	

LIMITED DISTRIBUTION

Copies of this report may be obtained only with the approval of the manager of the Dow Amines R&D Group. Limited for 20 years from date of issue.

Descriptive Summary and Conclusions

In recent years, natural gas producers have developed an alternative to Claus plant operation commonly called acid gas injection wherein the acid gas stream emerging from the regenerator overhead is compressed and injected into a subsurface reservoir. The costs associated with acid gas compression could be reduced if acid gas regeneration, which is currently done slightly above atmospheric pressure, could be accomplished at higher pressure. The purpose of this work is to explore the feasibility of regenerating at pressures substantially higher than currently practiced. Key findings are:

- Compression requirements associated with acid gas injection facilities could be substantially reduced if the acid gases were regenerated at substantially higher pressure than is currently practiced.
- Initial calculations suggest regeneration temperatures of about 290 – 300 F would be required to eliminate the first stage of compression, assuming no additional volatiles are present.
- Calculations suggest regeneration temperatures of 355 – 365 F would be needed to eliminate the first two stages of compression, assuming no additional volatiles are present.
- High pressure regeneration can be accomplished without a large increase in reboiler duty (energy consumption) if the lean rich exchanger is allowed to grow substantially

Patent Status: Disclosure Submitted: <input checked="" type="checkbox"/>	Case Filed: <input type="checkbox"/>	No Action Required: <input type="checkbox"/>
Are materials described in this report on your country's inventory? (TSCA, EINECS, etc.)	Yes: <input checked="" type="checkbox"/>	No: <input type="checkbox"/> *
Will this product be sold/used in other countries?	Yes: <input checked="" type="checkbox"/> *	No: <input type="checkbox"/>
*Contact your local regulatory compliance person and/or chief product steward.		
Restricted Distribution:	Distribution list on attached page.	

INTRODUCTION

The use of aqueous amines for the removal of acid gases (H_2S , CO_2 , COS, mercaptans etc.) from natural, synthesis and refinery gas streams has been described by many authors, including Kohl and Nielsen (1997). The acid gases are absorbed at high pressure and low temperature in an absorber and released at low pressure and high temperature in a regenerator. The concentrated acid gases are then commonly passed to a Claus plant which converts the hydrogen sulfide to sulfur. However, Claus plants have large capital and operating costs and the produced sulfur often has little or no commercial value.

In recent years, natural gas producers have developed an alternative to Claus plant operation commonly called acid gas injection wherein the acid gas stream emerging from the regenerator overhead is compressed and injected into a subsurface reservoir. The advantages and drawbacks of acid gas injection are described by Bosch (origin of this work is unknown, copy attached as Appendix A). This work additionally includes detailed descriptions of four acid gas injection facilities operated by Chevron Canada Resources over a period of years.

Design and construction of an acid gas injection facility requires knowledge of the phase behavior as a function of temperature, pressure, acid gas composition, water content, methane content etc. Certain physical properties such as heat capacity, density and viscosity are also important for specification of the compressors and heat exchangers required to achieve reservoir conditions. These aspects are covered by Carroll and Lui (1997), Carroll (1998 a & b), Carroll and Maddocks (1999) and Ng et. al. (1999).

Acid gas regeneration is most commonly accomplished in a steam stripper operated at the lowest possible pressure, typically a few psi (pounds per square inch) above atmospheric pressure. Since liquids under less pressure boil at lower temperatures, operating a steam stripper at the lowest possible pressure also allows operation at the lowest possible temperature. Low stripper temperatures translate into lower heating requirements, smaller heat exchangers etc. Additionally, if the liberated acid gases are fed to a conventional Claus plant or released into the atmosphere, regeneration at high pressure carries little or no value. However, if the liberated acid gases are to be compressed for subsurface injection (or any other reason), then regeneration at the lowest possible pressure may no longer represent the economic optimum. Hence, the purpose of this work is to explore the feasibility of regenerating at pressures substantially higher than currently practiced.

To provide focus, the West Pembina acid gas injection facility described by Bosch was selected as a basis of comparison. Currently H_2S and CO_2 scrubbed from natural gas by aqueous methyldiethanolamine (MDEA) are regenerated at 7 psig to produce an acid gas stream containing approximately 56 mole % H_2S , 39 mole % CO_2 , 3 mole % water, balance light hydrocarbons. Four stages of compression and cooling are used to boost the pressure to about 1,100 psia, with liquids removal (mostly water) after each cooler. The final cooler converts the entire stream to liquid for disposal into the subsurface formation.

RESULTS

Three cases were examined. The first case, which assumes a reboiler pressure of 23.3 psia, largely reproduces current operations and provides a basis of comparison. The second case assumes a reboiler pressure of 55.4 psia and eliminates one stage of compression. The third case assumes a reboiler pressure of 134.9 psia and eliminates two stages of compression. All three cases have the following common features:

- Total rich flow is 8971 lb-mole/hr
- Rich solvent consists of 43 wt % MDEA at 180 F loaded to 0.35 m/m with approximately equal amounts of H_2S and CO_2

- Rich solvent passes through a lean rich exchanger of sufficient size to provide a 35 F approach
- The heated rich solution is dumped into a 20 tray steam stripper. Regeneration pressure drops are 1 psi across the condenser, 2 psi across the stripper and 0.5 psi across the reboiler.
- Condenser T is 80.6 F
- Reboiler duty is 24.8 MMBTU/hr
- Compressor feed pressures are as reported by Bosch for West Pembina (22.7, 48.8, 128, 384 psia)
- Compressor discharge pressures are as reported by Bosch for West Pembina (49.9, 129, 389, 1066 psia)
- All calculations were performed using ASPEN/Ratefrac V 10.2. Physical property selections were Gas Treating Procomp™ 5 standard.

Full details for cases 1, 2 and 3 are provided in Appendix B, C and D respectively. Key calculation outcomes are summarized in Table 1.

Table 1 – Effect of Reboiler Pressure on Selected Plant Variables
(constant reboiler duty, 35 F exchanger approach)

	Case 1	Case 2	Case 3
Hot Lean T (F)	242	294	358
Hot Lean P (psia)	23.3	55.4	135
LRX Duty (MMBTU/hr)	5.9	18	36
Stripper Feed T (F)	207	259	323
Stripper Overhead T (F)	218	259	322
Reflux Cooler Duty (MMBTU/hr)	12	12	16
Reboiler Duty (MMBTU/hr)	24.8	24.8	24.8
Compressor 1 (HP)	170	0	0
Compressor 2 (HP)	211	211	0
Compressor 3 (HP)	231	232	233
Compressor 4 (HP)	176	175	173
Total Compression (HP)	788	618	406
Cooler 1 (MMBTU/hr)	.48	0	0
Cooler 2 (MMBTU/hr)	.65	.62	0
Cooler 3 (MMBTU/hr)	.80	.81	.85
Cooler 4 (MMBTU/hr)	Pc	Pc	Pc
Total Cooling (MMBTU/hr)	1.93	1.43	.85
Lean H2S (m/m)	5.1e-3	3.3e-3	4.2e-4
Lean CO2 (m/m)	3.2e-3	3.9e-3	5.6e-3

Pc=phase change due to differing estimates of where the 2-phase region for high pressure blends of CO2 and H2S starts. These duties were discarded as this aspect of the simulation does not greatly affect the arguments presented here.

Examination of Table 1 yields the following observations regarding elimination of the first stage of compression (Case 2 vs. Case 1):

- Elimination of the first stage of compression would reduce the total compression requirement from 788 HP to 618 HP, a reduction of about 22 %.
- Elimination of the first stage of compression would require the reboiler pressure to increase from 23.3 to 55.4 psia. This would, in turn, increase the reboiler temperature from about 242 F to about 294 F.

- The higher reboiler temperature combined with the 35 F approach requirement forces the exchanger duty to increase from 5.9 to 18 MMBTU/hr.
- Surprisingly, if the reboiler duty is kept constant at 24.8 MMBTU/hr the condenser duty remains substantially unchanged at 12 MMBTU/hr, despite the large change in temperature and pressure noted above. Examination of the column profiles in Appendix B and C reveals the amount of water returned as reflux has not substantially increased (587 lb-mole/hr in Case 1, 588 lb-mole/hr in Case 2).
- Elimination of the first stage of compression also eliminates the need for about 0.5 MMBTU/hr vapor phase cooling.

Examination of Table 1 yields the following observations regarding elimination of the first and second stages of compression (Case 3 vs. Case 1):

- Elimination of the first two stages of compression would reduce the total compression requirement from 788 HP to 406 HP, a reduction of about 48 %.
- Elimination of the first two stages of compression would require the reboiler pressure to increase from 23.3 to 135 psia. This would, in turn, increase the reboiler temperature from about 242 F to about 358 F.
- The higher reboiler temperature combined with the 35 F approach requirement forces the exchanger duty to increase from 5.9 to 36 MMBTU/hr.
- If the reboiler duty is kept constant at 24.8 MMBTU/hr the condenser duty increases from 12 to about 16 MMBTU/hr. The amount of water returned as reflux increases from 587 to 757 lb-mole/hr.
- Elimination of the first two stages of compression reduces the vapor phase cooling requirement by about 1.1 MMBTU/hr

A second set of calculations was undertaken to assess the effect of acid gas composition on compression and cooling requirements. These calculations, which are summarized in Figures 1 and 2, suggest the compression and cooling requirements to inject 100 lb-mole/hr acid gas are a weak function of H₂S/CO₂ proportions.

It should be noted that the high temperatures and pressures estimated by ASPEN/Ratefrac using the Procomp 5 physical property routines are outside the ranges intended when Procomp 5 was developed. In particular, certain characteristics of MDEA are not well known at temperatures in excess of 290 F. Hence, the lean loadings reported for Cases 2 and 3 are probably suspect. However, many of the above observations are strongly dependent on the thermal properties of water and on the properties of CO₂ and H₂S vapor, which are well known at these conditions.

The prospect of operating a steam stripper at elevated temperature and pressure raises questions about corrosion and thermal degradation. Corrosion questions are beyond the scope of this work, but thermal decomposition will be addressed somewhat. The data in Table 2 were extracted from the reactive chemicals database by Although the temperatures reported in Table 2 are
substantially higher than the temperatures contemplated in Table 1, these data do not guarantee these molecules will sustain repeated heating to 300 or 400 F over a period of months in a complex chemical environment. This point could be addressed with experiments.

Table 2 – Thermal decomposition of gas treating molecules
in the absence of oxygen

Material Tested	Decomposition T (F)	Method
Monoethanolamine	667	DSC
Diethanolamine	608	DSC
Triethanolamine	617	DSC
Methyldiethanolamine	493	ARC
Methylethanolamine	633	DSC
Tetraethylene glycol dimethylether	568	ARC
Tetraethylene glycol dimethylether	662	DSC

PRIOR ART

USP 5,766,548 – Includes a listing of typical amine solvent temperatures at various locations in the plant. These authors list 250 – 280 F as a typical reboiler temperature range.

USP 5,435,977 – A method of regenerating spent alkanolamine using modified regeneration tower. The modification consists of at least one internal flash section in the bottom portion of the regenerator.

USP 4,299,801 – Method for regenerating spent alkanolamine absorbing solution containing H₂S and CO₂. Two desorption stages are used to produce two acid gas streams – one rich in CO₂ and the other rich in H₂S. Both regeneration stages are conducted at conventional temperature and pressure (8-12 psig) conditions.

USP 4,452,763 – A process for regeneration of spent aqueous alkanolamine or dialkanolamine. Energy consumption is reduced by minimizing the amount of water circulated (10 to 35 wt % water) and by minimizing the amount of reflux returned to the top of the regeneration tower. No advantage to operation at high regeneration pressure is disclosed. Regenerator bottoms temperature in the example is 140 C, consistent with normal practice.

USP 4,152,217 – A process for regenerating a spent aqueous amine absorbent. Improvement involves splitting the spent absorbent into two portions. One portion is not heated but is directed to the regenerator top. The other portion is heated and introduced at an intermediate height of the regenerator. No advantage to operation at high regeneration pressure is disclosed. The example includes a reboiler temperature of 262 F, consistent with normal operating practice.

US 2002/0007733 – Use of fuel gas to strip benzene, toluene and xylene (BTX) from a liquid amine stream. This stripping is accomplished in a separate vessel. The liquid amine exiting the BTX stripper is then heated and passed to a conventional stripper. No teaching of any advantage to operating at high stripper pressure.

USP 5,660,603 – Removal of CO₂ at high pressure from natural gas by contacting with water or seawater. Absorber temperature and pressure are selected to allow the formation of pre-solid hydrates in the aqueous phase. Regeneration of the aqueous phase is accomplished by altering the temperature and

pressure to allow decomposition of the pre-solid hydrate structures. This pressure can be greater than or less than the absorption pressure.

CONCLUSIONS

Compression requirements associated with acid gas injection facilities could be substantially reduced if the acid gases were regenerated at substantially higher pressure than is currently practiced.

Initial calculations suggest regeneration temperatures of about 290 – 300 F would be required to eliminate the first stage of compression, assuming no additional volatiles are present.

Calculations suggest regeneration temperatures of 355 – 365 F would be needed to eliminate the first two stages of compression, assuming no additional volatiles are present.

High pressure regeneration can be accomplished without a large increase in reboiler duty (energy consumption) if the lean rich exchanger is allowed to grow substantially.

Figure 1 - Effect of Regeneration Pressure
on Compression Requirement

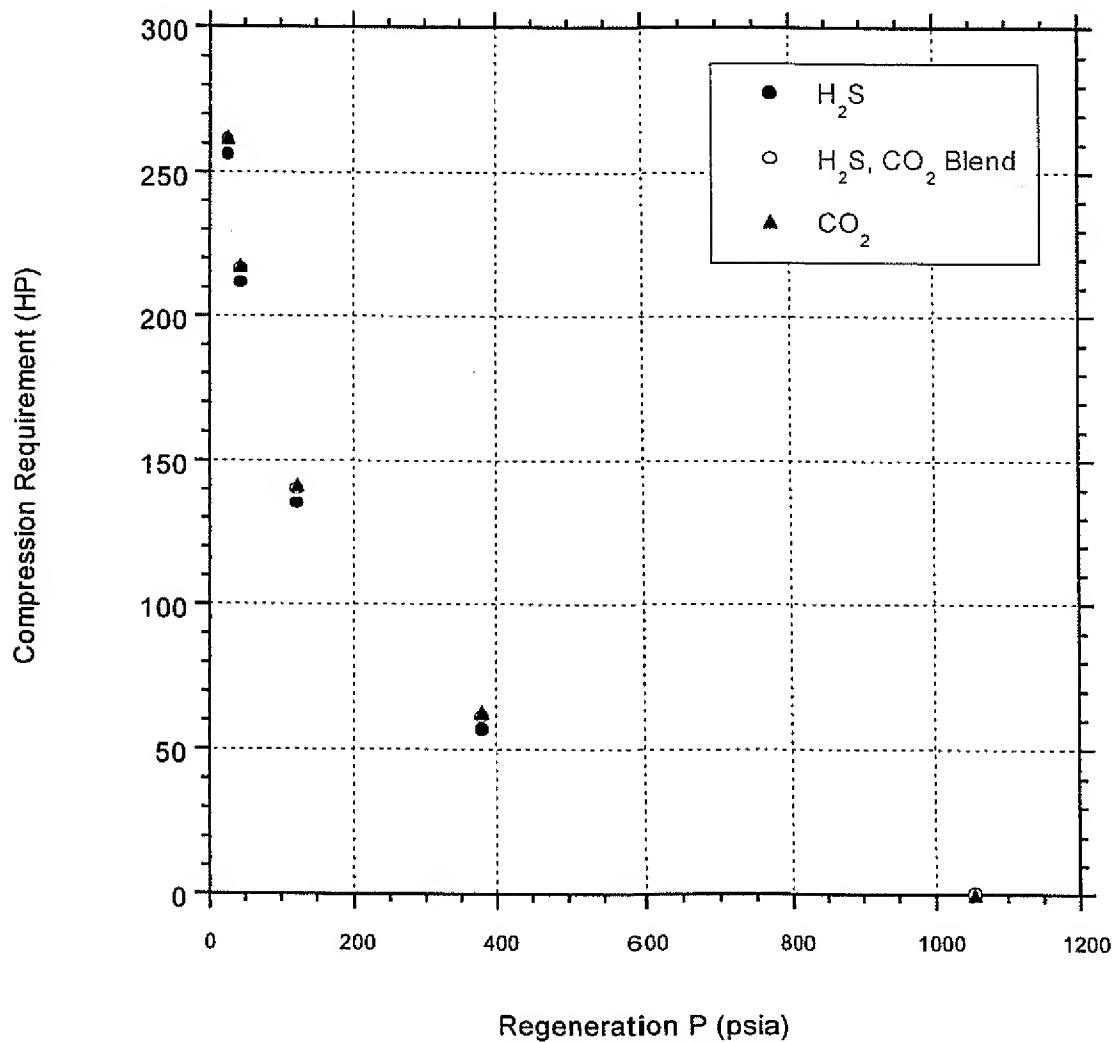
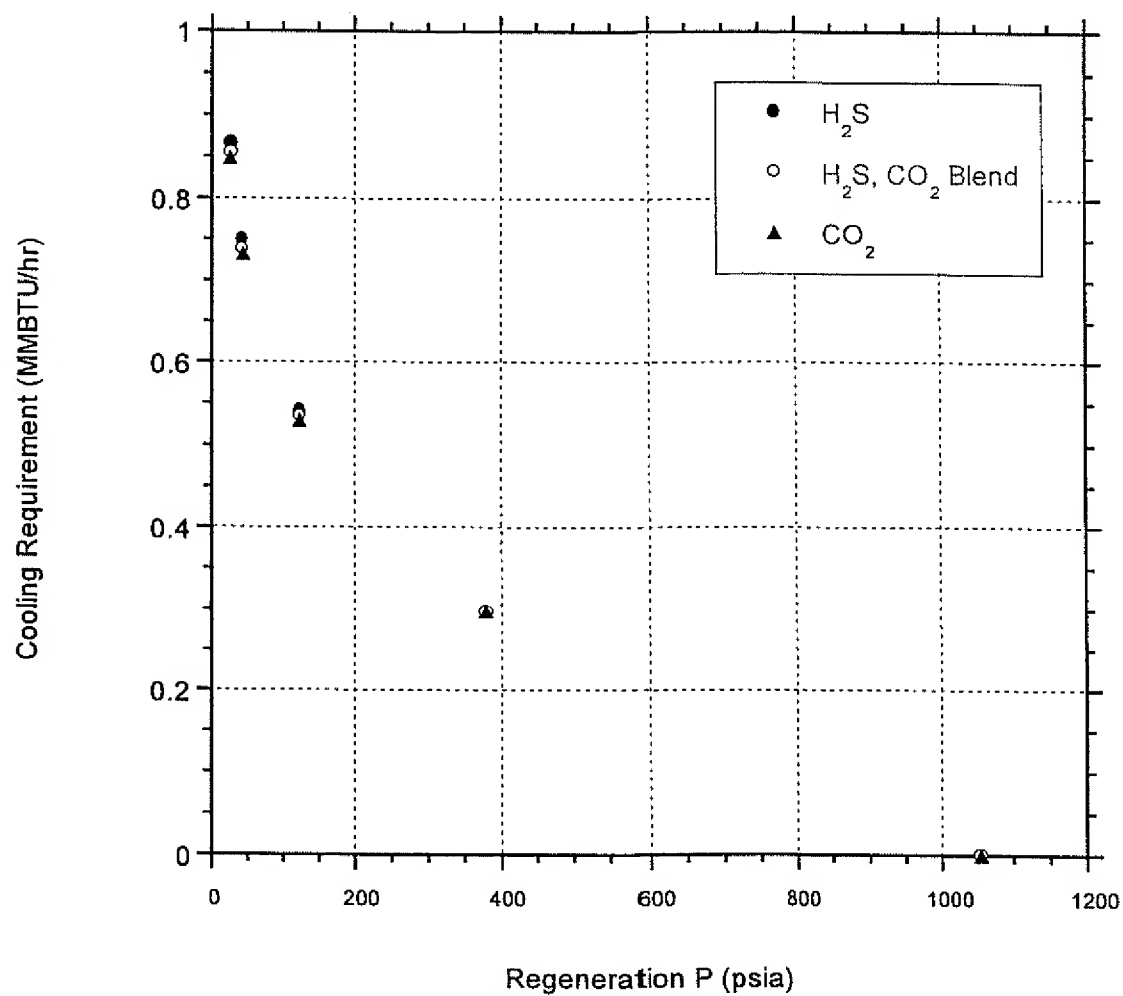


Figure 2 - Effect of Regeneration Pressure
on Cooling Requirement



BIBLIOGRAPHY

Bosh, Neil "Acid Gas Injection – A Decade of Operating History in Canada"

Chao, I-Meen, USP 5,435,977 "Acid Gas Removal System Employing Regenerator with Internal Flash Section".

Corroll, J. J., D. W. Lui, "Density, Phase Behavior Keys to Acid Gas Injection", Oil & Gas J., **95** (25), 63-72 (1997).

Carroll, J. J., "Phase Diagrams Reveal Acid-Gas Injection Subtleties", Oil & Gas J., **96** (9), 92-96 (1998a).

Carroll, J. J., "Acid Gas Injection Encounters Diverse H₂S, Water Phase Changes", Oil & Gas J., **96** (10), 57-59 (1998b).

Carroll, J. J., James R. Maddocks "Design Considerations for Acid Gas Injection", Laurance Reid Gas Conditioning Conference (1999).

Eisenberg, Benjamin, Russell R. Johnson, USP 4,152,217 "Amine Regeneration Process".

Elliot, Douglas G., J. J. Chen, USP 5,660,603 "Process for Separating Selected Components from Multi-Component Natural Gas Streams".

Kohl, A. L., R. B. Nielsen "Gas Purification" Gulf Publishing Company (1997).

Kraats, Eduard J. van de, Richard C. Darton, USP 4,452,763 "Process for Regeneration of Solvents in Hydrogen sulfide Removal from Gases".

Lynn, James B., J. A. Laslo, O. A. Hornberg, USP 4,299,801 "Regenerating Alkanolamine Desulfurizer Solutions".

Morrow, David, USP Application 2002/0007733 "Raw Natural Gas Processing System and Method of Processing Raw Natural Gas".

Ng, H.-J., J. J. Carroll, . R. Maddocks, "Impact of Thermophysical Properties Research on Acid Gas Injection", 78th Annual GPA Convention, March (1999).

Soria, John, USP 5,766,548 "Method for Minimizing Solvent Degradation and Corrosion in Amine Solvent Treatment Systems".